**ECONOMIC IMPACT ANALYSIS**
**(Final Analysis)**

**Item Title:** Regulation Number 7, Sections II., XII., XVII., XVIII.

**Meeting Date:** October 19 and 20, 2017

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## ISSUE

On May 4, 2016, the U.S. Environmental Protection Agency's ("EPA") published a final rule that determined that Colorado's Marginal ozone nonattainment area failed to attain the 2008 8-hour Ozone National Ambient Air Quality Standard ("NAAQS"). EPA, therefore, reclassified the Denver Metro North Front Range ("DMNFR") area to Moderate and required attainment of the NAAQS no later than July 20, 2018, based on 2015-2017 ozone data.

As a result of the reclassification, Colorado submitted revisions to its State Implementation Plan ("SIP") to address the Clean Air Act's ("CAA") Moderate nonattainment area requirements, as set forth in CAA § 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (*See* 80 Fed. Reg. 12264 (March 6, 2015)). As a Moderate nonattainment area, Colorado must revise its SIP to include Reasonably Available Control Technology ("RACT") requirements for each category of volatile organic compound ("VOC") sources covered by a Control Technique Guideline ("CTG") for which Colorado has sources in the DMNFR that EPA finalized prior to a nonattainment area's attainment date. EPA finalized the Control Techniques Guidelines for the Oil and Natural Gas Industry ("Oil and Gas CTG") on October 27, 2016, with a state SIP submittal deadline of October 27, 2018 (*See* 81 Fed. Reg. 74798 (October 27, 2016)). Given this timing, the November, 2016, SIP revisions did not include RACT for the oil and natural gas source category and Colorado must further revise its SIP. The Air Quality Control Commission ("Commission") submitted the November SIP revisions to EPA on May 31, 2017.

The Oil and Gas CTG recommends controls that are presumptively approvable as RACT and provide guidance to states in developing RACT for their specific sources. In many cases, Colorado has similar, or more stringent, regulations comparable to the recommendations in the Oil and Gas CTG, though many of these provisions are not currently in Colorado's Ozone SIP. The Division now requests that the Commission consider proposed revisions to Regulation Number 7 to include RACT requirements for each category of sources covered by EPA's Oil and Gas CTG in Colorado's Ozone SIP. These proposed revisions duplicate existing State-Only requirements for inclusion in Colorado's Ozone SIP, propose new requirements for inclusion in Colorado's Ozone SIP, and revise and/or clarify existing SIP and State-Only provisions.

Specifically, the Division proposes to duplicate the centrifugal and reciprocating compressor emission control requirements from existing Regulation Number 7, Section XVII.B.3. in proposed Section XII.J., along with new monitoring and recordkeeping requirements. The Division also proposes to create a well production facility and natural gas compressor station leak detection and repair ("LDAR") program in proposed Section XII.L., generally consistent with the existing State-Only program in Section XVII.F. but increasing the inspection frequency for smaller well production facilities and natural gas compressor stations. The Division proposes to include new pneumatic pump emission control, monitoring, and recordkeeping requirements in proposed Section XII.K. The Division's proposal includes provisions to increase the stringency of the LDAR program for equipment leaks at natural gas processing plants in existing SIP Section XII.G. The Division proposes to incorporate some of the existing Section XVIII. State-Only requirements for continuous bleed, natural gas-driven pneumatic controllers into the SIP and to require, as part of the SIP, zero bleed pneumatic controllers at natural gas processing plants.

In addition, the Division proposes State-Only revisions that require owners or operators of natural gas-driven pneumatic controllers located at a well production facility or natural gas compressor station in the DMNFR to inspect and maintain pneumatic controllers. Current information indicates these devices are a large source of emissions and that returning these device to proper operation can cost-effectively reduce excess emissions. The Oil and Gas CTG does not specifically recommend pneumatic controller inspection and maintenance provisions as RACT; therefore, the Division proposes to include these requirements as State-Only revisions.

These proposed revisions satisfy Colorado's Moderate CAA requirements and obtain emission reductions necessary to help the DMNFR attain the 2008 8-hour ozone NAAQS.

Further, the Division may also make clarifying revisions and typographical, grammatical, and formatting corrections throughout Regulation Number 7.

The proposed revisions to Regulation Number 7, Sections II., XII. and some revisions to Section XVIII. are SIP revisions. The proposed revisions to Section XVII. and some revisions to Section XVIII. are State-Only.

**REQUIREMENTS FOR ECONOMIC IMPACT ANALYSIS ("EIA")**

Section 25-7-110.5(4)(a), C.R.S. sets forth the requirements for the initial and final Economic Impact Analysis, as stated below:

> Before any permanent rule is proposed pursuant to this section, an initial economic impact analysis shall be conducted in compliance with this subsection (4) of the proposed rule or alternative proposed rules. Such economic impact analysis shall be in writing, developed by the proponent, or the Division in cooperation with the proponent and made available to the public at the time any request for hearing on a proposed rule is heard by the commission. A final economic impact analysis shall be in writing and delivered to the technical secretary and to all parties of record five working days prior to the prehearing conference. If no prehearing conference is scheduled, the economic impact analysis shall be submitted at least ten working days before the date of the rule-making hearing. The proponent of an alternative proposal will provide, in conjunction with the Division, a final economic impact analysis five working days prior to the prehearing conference. The economic impact analyses shall be based upon reasonably available data. Except where data is not reasonably available, or as otherwise provided in this section, the failure to provide an economic impact analysis of any noticed proposed rule or any alternative proposed rule will preclude such proposed rule or alternative proposed rule from being considered by the Commission. Nothing in this section shall be construed to restrict the Commission's authority to consider alternative proposals and alternative economic impact analyses that have not been submitted prior to the prehearing conference for good cause and so long as parties have adequate time to review them.

Per Section 25-7-110.5(2), C.R.S., the requirements of Section 25-7-110.5(4) shall not apply to rules which: (1) adopt by reference applicable federal rules; (2) adopt rules to implement prescriptive state statutory requirements where the AQCC is allowed no significant policy-making options; or, (3) adopt rules that have no regulatory impact on any person, facility or activity.

**DISCUSSION**

To satisfy Colorado's Moderate nonattainment area CAA obligations to revise Colorado's SIP to include provisions that implement RACT for every VOC source category covered by a CTG, the

Division is proposing to include RACT requirements for existing and new centrifugal compressors, reciprocating compressors, pneumatic pumps, pneumatic controllers, equipment leaks at natural gas processing plants, and fugitive emissions at well production facilities and natural gas compressor stations in the DMNFR in Colorado's Ozone SIP. Where possible, the proposed revisions build upon existing Regulation Number 7 requirements.

There may be minimal economic impacts of the proposed revisions for owners or operators of centrifugal compressors, reciprocating compressors, and continuous bleed pneumatic controllers in the DMNFR as the proposed revisions include additional monitoring and/or recordkeeping requirements than are currently required under State-Only provisions. The State-Only provisions currently require the emission control measures proposed for inclusion in Colorado's Ozone SIP.

There may be economic impacts of the proposed revisions for owners or operators of reciprocating compressors at natural gas processing plants in the DMNFR as the proposed revisions require owners or operators replace reciprocating compressor rod packing or route emissions to a process. Similarly, there may be economic impacts of the proposed revisions for owners or operators of continuous bleed, natural gas-driven pneumatic controllers at natural gas processing plants in the DMNFR as the proposed revisions require zero bleed pneumatic controllers. These proposed revisions also include recordkeeping and potential monitoring requirements. The current State-Only requirements do not apply to reciprocating compressors at natural gas processing plants and only require low-bleed pneumatic controllers at natural gas processing plants.

There may be economic impacts of the proposed revisions for owners or operators of natural gas processing plants in the DMNFR as the proposed revisions revise the LDAR program minimum from a Subpart VV level program to a Subpart VVa level program, which increases the repair threshold stringency for some equipment. Colorado's Ozone SIP currently requires a minimum Subpart VV level program for natural gas processing plants in the DMNFR.

There may be economic impacts of the proposed revisions for owners or operators of pneumatic pumps at well production facilities and natural gas processing plants in the DMNFR as the proposed revisions require 95% control of VOC emissions or establish a zero emission standard. The proposed revisions also include monitoring and recordkeeping requirements. Regulation Number 7 does not currently include any requirements for pneumatic pumps.

There may be economic impacts of the proposed revisions for owners or operators of well production facilities and natural gas compressor stations in the DMNFR as the proposed revisions increase the frequency of the LDAR inspections at some facilities. The proposed revisions also add additional detail to the recordkeeping and reporting requirements than are currently required under State-Only provisions. The State-Only provisions currently specify different inspection frequencies than those proposed for inclusion in Colorado's Ozone SIP.

Lastly, there may be economic impacts of the proposed revisions for owners or operators of natural gas-driven pneumatic controllers located at or upstream of a natural gas processing plant in the DMNFR as the proposed revisions require owners or operators to inspect and return pneumatic controllers to proper operation. The proposed revisions also include recordkeeping and reporting requirements. Regulation Number 7 does not currently include inspection and maintenance requirements for all pneumatic controllers.

The degree of potential impact of the proposed revisions may be site specific and depend on the owner or operator's current required, or voluntary, control, monitoring, and recordkeeping program for the existing pieces of equipment. The impacts of the proposed revisions for new pieces of equipment or facilities can be more readily accounted for prior to installation or construction, but are also unknown. The Division relies on cost data supporting the Oil and Gas

CTG in addition to cost data the Division has independently collected. Some stakeholders have raised concerns with the Oil and Gas CTG cost data. In response to these concerns and to more generally support its proposals, the Division requested that industry provide cost information concerning the impacts of the proposed revisions. Except for general cost impacts related to equipment leaks at natural gas processing plants, the Division has not yet received such requested information.

Based on the data the Division has at this time, the Division provides the following information to satisfy the economic analysis relating to the above described oil and gas industry emission sources, as a result of the proposed revisions to Regulation Number 7:

(A) Identification of the industrial and business sectors that will be impacted by the proposal;
(B) Quantification of the direct cost to the primary affected business or industrial sector; and
(C) Incorporation of an estimate of the economic impact of the proposal on the supporting business and industrial sectors associated with the primary affected business or industry sectors.

Section 25-7-110.5(4)(c)(III), C.R.S.

**(A) Identification of the industrial and business sectors that will be impacted by the proposal**

Oil and gas industry owners and operators of the following existing and new emission sources in the DMNFR may be impacted by the proposed revisions:

- Centrifugal compressors using wet seals and located between the wellhead and the point of custody to the natural gas transmission and storage segment, but not including the well production facility;
- Reciprocating compressors located between the wellhead and the point of custody to the natural gas transmission and storage segment, but not including the well production facility;
- Natural gas-driven diaphragm pneumatic pumps located at a well production facility or natural gas processing plant;
- Continuous bleed natural gas-driven pneumatic controllers located at or upstream of a natural gas processing plant;
- Equipment within a process unit located at an onshore natural gas processing plant;
- Fugitive emission components at a well production facility or natural gas compressor station; and
- Natural gas-driven pneumatic controllers located at or upstream of a natural gas processing plant.

**(B) Quantification of the direct cost to the primary affected business or industrial sector**

Below is a summary table of the cost analyses of the proposed revisions. Note that in some instances the costs and benefits may vary from facility to facility. This is particularly true in the context of LDAR costs and benefits, which can vary significantly from facility to facility. The costs and benefits identified below represent averages based on the best information available to the Division.

| *Summary Table: Total Cost of Proposed Regulation* | | | | | |
|---|---|---|---|---|---|
| Description (# in DMNFR) | Item | # of Affected Facilities | Net Total Costs | VOC Reduction [tpy] | VOC Control Cost [$/ton] |

| Summary Table: Total Cost of Proposed Regulation | | | | | |
|---|---|---|---|---|---|
| Description (# in DMNFR) | Item | # of Affected Facilities | Net Total Costs | VOC Reduction [tpy] | VOC Control Cost [$/ton] |
| Natural Gas Processing Plants (16) | Centrifugal compressor emission control, monitoring, and recordkeeping | not reported | Minimal | NA | NA |
| | Reciprocating compressor rod packing replacements, monitoring, and recordkeeping | 133 | Minimal to $1,631 / compressor | 4.89/compressor | $334 |
| | Pneumatic pump retrofit, monitoring, and recordkeeping | not reported | Minimal to $72,394 / pump | 0.96 | ? |
| | Pneumatic controller retrofit, monitoring, and recordkeeping | not reported | $0 - $2,000 / controller | Up to 33.1/facility | $6 - $68 / controller |
| | LDAR inspections at NSPS VVa (NSPS OOOO) level | 16 | $12,959/ facility | 4.56/facility | $2,844 |
| Natural Gas Compressor Stations (73) | Centrifugal compressor emission control, monitoring, and recordkeeping | not reported | Minimal | NA | NA |
| | Reciprocating compressor rod packing replacements, monitoring, and recordkeeping | not reported | Minimal | NA | NA |
| | Pneumatic controller retrofit to low bleed, monitoring, and recordkeeping | not reported | Minimal | NA | NA |
| | LDAR inspections, repair, reporting, and recordkeeping | 53 | $252,254 | 111 | $2,273 |
| | (State Only) Pneumatic controller inspections, reporting, and recordkeeping | ? | $0-$500 | ? | ? |
| Well Production Facilities (7,264) | Pneumatic pumps emissions controls, monitoring, and recordkeeping | 230 | $5,433/pump | 0.91/pump | $847 |
| | Pneumatic controller retrofit to low bleed and recordkeeping | 2,500 | Minimal | NA | NA |
| | LDAR inspections at annual frequency, repair, | 2,958 | $3,681,396 | 5,324 | $691 |

| *Summary Table: Total Cost of Proposed Regulation* | | | | | |
|---|---|---|---|---|---|
| Description (# in DMNFR) | Item | # of Affected Facilities | Net Total Costs | VOC Reduction [tpy] | VOC Control Cost [$/ton] |
| | recordkeeping, and reporting | | | | |
| | LDAR inspections at semi-annual frequency, repair, recordkeeping, and reporting | 1,370 | $1,301,329 | 685 | $1,900 |
| | (State Only) Pneumatic controller inspections, recordkeeping, and reporting | 53,000 | $0-$500 | ? | ? |

Centrifugal and reciprocating compressors (Section XII.J.)

The Oil and Gas CTG recommends emission control requirements for reciprocating compressors and centrifugal compressors using wet seals and located between the wellhead and point of custody transfer to the natural gas transmission and storage segment, excluding the well site. Regulation Number 7, Section XVII.B.3. includes similar control requirements. However, Section XVII.B.3. is not part of Colorado's ozone SIP. Therefore, the proposed revisions duplicate the emission control requirements from Section XVII.B.3. in Section XII. to include the requirements in Colorado's ozone SIP, and add minimal monitoring and recordkeeping requirements to ensure and demonstrate compliance with the emission control requirements.

There are no additional costs related to including the compressor emission control requirements for reciprocating compressors at natural gas compressor stations or centrifugal compressors in Colorado's Ozone SIP because these requirements are already required as a State-Only provision. There may be costs related to the proposed monitoring and recordkeeping requirements as owners or operators may have to conduct cover and closed vent system inspections, document such inspections, or track and document compressor operating hours. However, the Division believes that these costs are minimal as owners or operators will be able to incorporate the monitoring and recordkeeping requirements into their existing monitoring and recordkeeping programs. In addition, some compressors may already be subject to similar requirements under 40 CFR Part 60, Subparts OOOO or OOOOa and will be able to demonstrate compliance with the proposed monitoring and recordkeeping requirements by complying with the monitoring and recordkeeping requirements in Subparts OOOO or OOOOa, instead of complying with duplicative requirements in Regulation Number 7.

There may be additional costs of the proposed requirement for owners or operators of reciprocating compressors at natural gas processing plants to replace the rod packing or route emissions to a process. The Division estimates that there are sixteen natural gas processing plants in the ozone nonattainment area, with an estimated 133 engines. Conservatively assuming these 133 engines existing at the natural gas processing plants are all reciprocating engines and would be subject to the proposed requirements, it is unknown how many owners or operators voluntarily replace rod packing or capture engine emissions and therefore would not have to implement a new emission control program. However, the Oil and Gas CTG estimates the capital cost of replacing the rod packing at $4,280 and the cost per ton of VOC reduced at $334, without factoring in the natural gas savings.[1] The estimated emissions reduction benefit

[1] Oil and Gas CTG at p. 5-13, Table 5-5.

is 4.89 tons VOC per compressor per year.[2] Concerning the option to route VOC emissions to a process, the Oil and Gas CTG assumed that costs would be minimal for an owner or operator to route emissions to an existing vapor recovery unit.[3] In addition, there may be minimal costs related to the proposed monitoring and recordkeeping requirements, as discussed above, where an owner or operator is not currently monitoring and keeping compressor records.

Pneumatic pumps (Section XII.K.)

The Oil and Gas CTG recommends emission control requirements for natural gas-driven diaphragm pumps located at well sites and natural gas processing plants. Regulation Number 7 does not include requirements for pneumatic pumps. Therefore, the proposed revisions include an emission control requirement for pneumatic pumps at well production facilities, an emission standard for pneumatic pumps at natural gas processing plants, and associated monitoring and recordkeeping.

There may be costs of the proposed requirement for owners or operators to control emissions from pneumatic pumps at well production facilities. The Division estimates that there are approximately 7,264 well production facilities in the DMNFR and the 2017 ozone emissions inventory estimated approximately 230 pneumatic pumps at well sites. However, the Division does not have data as to what type of pneumatic pumps were reported (e.g., diaphragm or plunger/piston) and whether the facility has an existing control device onsite. The Oil and Gas CTG estimates the capital cost for routing emissions to an existing control device at $5,433, with a cost per ton of VOC reduced at $847, without gas savings.[4] The Division is assuming that most pumps at well production facilities are diaphragm pumps. The Oil and Gas CTG estimated an emissions reductions benefit of 0.91 tpy VOC per pump.[5] The Division requested information from industry to better quantify the benefits of this control measure.

There may be costs of the proposed requirement for owners or operators to ensure that pneumatic pumps at natural gas processing plants have an emission rate of zero. The Division estimates that there are sixteen natural gas processing plants in the ozone nonattainment area, but does not have the data as to the quantity of natural gas-driven diaphragm pumps at the natural gas processing plants. Similarly, EPA did not have data to characterize the number and types of gas-driven pumps at natural gas processing plants. EPA estimated in the 2016 NSPS OOOOa Technical Support Document ("TSD") emissions and costs for small to large model natural gas processing plants, ranging from 4 to 100 total pumps at 25 to 75% pump distribution scenarios. The 2016 NSPS OOOOa TSD estimates annual costs to replace compressors in an existing instrument air system in order to increase capacity to operate the pumps from $10,051 to $72,394.[6] EPA also assumes in the Oil and Gas CTG that existing natural gas processing plants have an instrument air system in place and the cost of increasing the air load on the system would be associated with the incremental cost of connecting the pneumatic pumps to the existing system.[7] The Oil and Gas CTG utilizes the above described cost estimates from the 2016 NSPS OOOOa TSD and estimates VOC reductions from converting a pneumatic pump to instrument air at 0.96 tpy per pump.[8] In addition, the Oil and Gas CTG estimates the capital cost for a solar-powered electric pump at $2,227 and the value of the natural gas saved per diaphragm pump at $786 per year.[9] The Oil and Gas CTG also estimates the cost of an electric

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[2] Id. at p. 5-12, Table 5-4.
[3] Id. at p. 5-16.
[4] Id. at p. 7-13, Table 7-4.
[5] Id.
[6] Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources - Background Technical Support Document for the Final New Source Performance Standards 40 CFR Part 60, subpart OOOOa, at p.83, Table 6-4 (May 2016).
[7] Oil and Gas CTG at p. 7-10.
[8] Id. at p. 7-11.
[9] Id. at p. 7-8.

pump at $4,647, annualized costs at $954, and the value of the natural gas saved per diaphragm pump at $786 per year.[10]

There may also be costs related to the proposed monitoring and recordkeeping requirements as owners or operators may have to conduct and document control system inspections and keep records related to pneumatic pumps. However, the Division believes that these costs are minimal as owners or operators will be able to rely upon their existing monitoring and recordkeeping programs to incorporate the proposed monitoring and recordkeeping requirements. In addition, some pneumatic pumps may already be subject to similar requirements under 40 CFR Part 60, Subpart OOOOa and will be able to demonstrate compliance with the proposed requirements by complying with Subpart OOOOa.

Continuous bleed pneumatic controllers (Sections XVIII.C. through E.)

The Oil and Gas CTG recommends emission control requirements for continuous bleed, natural gas-driven pneumatic controllers located from the wellhead through the natural gas processing plant. Regulation Number 7, Section XVIII. currently requires low-bleed pneumatic controllers at or upstream of natural gas processing plants. Section XVIII. is not part of Colorado's Ozone SIP. Therefore, the proposed revisions remove "State-Only" designations from the pneumatic controller requirements applicable in the DMNFR to include the requirements in Colorado's Ozone SIP. The proposed revisions also require that pneumatic controllers at natural gas processing plants maintain a natural gas bleed rate of zero, which is consistent with the Oil and Gas CTG recommendations.

There are no additional costs related to including the low-bleed requirement for pneumatic controllers located from the wellhead to a natural gas processing plant in Colorado's Ozone SIP because this requirement is already required as a State-Only provision.

There may be costs related to the proposed requirement for owners or operators of natural gas processing plants to ensure that natural gas-driven pneumatic controllers have a bleed rate of zero. The Division estimates that there are sixteen natural gas processing plants in the ozone nonattainment area, but does not have data on the quantity of natural gas actuated pneumatic controllers at the natural gas processing plants. The Oil and Gas CTG assumes that existing natural gas processing plants have already replaced pneumatic controllers with other types of control, such as an instrument air system, and any pneumatic controllers with a bleed rate greater than zero are required due to safety reasons.[11] Therefore, the Division believes the cost to owners or operators of natural gas processing plants of the proposed requirements are minimal and limited to documenting, tagging, and maintaining any natural gas-driven pneumatic controllers with a bleed rate greater than zero that are required for safety and/or process purposes. Should an owner or operator of a natural gas processing plant convert an existing natural gas-driven pneumatic controller to their instrument air system, the Oil and Gas CTG estimates a capital cost of converting the pneumatic controller at $2,000 and the cost per ton of VOC reduced between $6 and $68 per pneumatic controller.[12] An emissions reduction of up to 33 tons per year is associated with each natural gas processing plant. Because the Division assumed that most of the natural gas processing plants in the DMNFR would probably require a medium-to-large air system, this number represents an average of the VOC reduction associated with converting mostly medium and large sized gas plants to system air.[13]

There may also be costs related to the proposed recordkeeping requirements as owners or operators may have to compile and retain documentation concerning their continuous bleed pneumatic controllers. For example, the Division estimates that there are approximately 7,264

[10] Id. at p. 7-9.
[11] Id. at p. 6-16.
[12] Id.
[13] Id. at p.6-17, Table 6-7.

well production facilities in the DMNFR with approximately 2,500 natural gas-driven low-bleed pneumatic controllers. Under the proposed revisions, owners or operators of these low-bleed pneumatic controllers will have to keep records documenting that the pneumatic controller is low-bleed. In addition, owners or operators of continuous bleed, natural gas-driven pneumatic controllers at natural gas processing plants will have to keep records demonstrating that the pneumatic controller has a bleed rate of zero or justifying a bleed rate greater than zero. However, the Division believes that owners or operators will be able to incorporate the recordkeeping requirements into their existing recordkeeping programs with minimal cost. Further, owners or operators should already have some record of the low-bleed status of their continuous bleed pneumatic controllers located upstream of the natural gas processing plant because the Division has not received justifications for a high-bleed pneumatic controller in that sector. There are no additional costs related to records of high-bleed pneumatic controllers because records are already required as a State-Only provision.

Equipment leaks at natural gas processing plants (Section XII.G.)

The Oil and Gas CTG recommends a minimum LDAR program equivalent to 40 CFR Part 60, Subpart VVa for existing and new natural gas processing plants. Natural gas processing plants in the DMNFR are currently required to comply with, at a minimum, the equipment LDAR program in 40 CFR Part 60, Subpart KKK. Subpart KKK relies on the LDAR program in 40 CFR Part 60, Subpart VV. In contrast, 40 CFR Part 60, Subparts OOOO and OOOOa rely on the LDAR program in Subpart VVa. Therefore, the proposed revisions replace the reference to Subpart KKK with Subpart OOOO. Requiring owners or operators of natural gas processing plants to comply with, at a minimum, the equipment LDAR program in Subpart OOOO lowers the leak detection thresholds for pumps in light liquid service, valves in gas/vapor service and in light liquid service, connectors in gas/vapor service and in light liquid service, and pressure relief devices in gas/vapor service, as compared to Subpart KKK.

The Division estimates that there are sixteen natural gas processing plants in the DMNFR. Of these, six are subject to the Subpart KKK LDAR program, five are subject to the Subpart OOOO LDAR program, one is subject to the Subpart OOOOa LDAR program, and four are subject to both the Subparts KKK and OOOO LDAR programs for different equipment. Therefore, only six natural gas processing plants will require full conversions to a Subpart OOOO LDAR program, and only four natural gas processing plants will require partial conversions. In response to information the Division received on general costs impacts, the proposed revisions establish a January 1, 2019, implementation date in recognition of the time and resources necessary for the owner or operator of an existing natural gas processing plant to transition from a Subpart KKK to Subpart OOOO LDAR program.

Compliance with the Subpart OOOO LDAR program will require the owners or operators of the natural gas processing plants subject, wholly or in part, to the Subpart KKK LDAR program to repair pumps in light liquid service, valves in gas/vapor service and in light liquid service, connectors in gas/vapor service and in light liquid service, and pressure relief devices in gas/vapor service at a lower leak detection threshold. The proposed revisions, therefore, may result in additional repair or equipment replacement costs for such facilities. However, the proposed revisions will also result in additional emission reductions, and product savings, due to a potential increase in the repair of leaks. The Oil and Gas CTG estimated that the incremental capital cost of implementing a Subpart VVa (Subpart OOOO) level LDAR program from a baseline Subpart VV (Subpart KKK) LDAR program was $12,959 per natural gas processing plant.[14] The Oil and Gas CTG estimated an annual emissions reduction of 4.56 tpy VOC.[15] The Oil and Gas CTG also estimated that the cost per ton of VOC reduced was $2,844, and $2,010 after including natural gas savings.[16] These estimates were made for a model natural gas

[14] Id. at p. 8-11.
[15] Id.
[16] Id.

processing plant wholly subject to a Subpart VV (Subpart KKK) level LDAR program. The Oil and Gas CTG model natural gas processing plant included 1,392 valves, 4,392 connectors, 134 open-ended lines, and 29 pressure relief valves.[17] The Division assumes costs will be less for the owner or operator of four natural gas processing plants because they are already partially subject to the Subpart VVa (Subpart OOOO) LDAR program.

Fugitive emissions at well production facilities and natural gas compressor stations (Section XII.L.)

The Oil and Gas CTG recommends a LDAR program to reduce fugitive emissions from components at well sites and gathering and boosting stations located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or point of custody transfer to an oil pipeline. Regulation Number 7, Section XVII.F. currently requires owners or operators of well production facilities and natural gas compressor stations that are located downstream of a natural gas processing plant inspect components for leaks and repair detected leaks. Section XVII.F. is not part of Colorado's ozone SIP. In addition, the Oil and Gas CTG recommends a fixed inspection frequency using optical gas imaging ("OGI") or EPA Method 21. In contrast, Section XVII.F. includes a tiered inspection frequency using infra-red camera or Method 21 ("approved instrument monitoring method" or "AIMM") based on facility emissions and a fixed inspection frequency using AVO for well production facilities. The proposed revisions duplicate provisions from Section XVII.F. in proposed Section XII. to include the requirements in Colorado's Ozone SIP and build on Colorado's existing LDAR framework.

The Division estimates, based on Air Pollution Emission Notice ("APEN") reported data, that there are 7,264 well production facilities in the DMNFR, with an estimated 4,328 (1 tpy to ≤ 12 tpy facilities) potentially impacted by the proposed increase in inspection frequency. Of the 4,328 potentially impacted well production facilities, an estimated 2,958 have uncontrolled actual VOC emissions greater than one ton per year ("tpy") but less than or equal to six tpy, and an estimated 1,370 have emissions greater than six tpy but less than or equal to 12 tpy. The Division estimates that there are 72 natural gas compressor stations in the DMNFR and 53 (≤ 12 tpy facilities) potentially impacted by the proposed increase in inspection frequency.

The Division proposes to revise the inspection frequencies for natural gas compressor stations as set forth in Table A.

***Table A: Proposed Leak Inspection Frequencies Leak at Compressor Stations***

| Component Leak Uncontrolled Actual VOC Emissions | Current Inspection Frequency | Proposed Inspection Frequency |
|---|---|---|
| ≤ 12 tpy | Annually | Quarterly |
| >12 tpy to ≤ 50 tpy | Quarterly | No Change |
| > 50 tpy* | Monthly | No Change |

**There are currently no compressor stations in Colorado with calculated leaks at this level*

The Division proposes to revise the inspection frequencies for well production facilities as shown in Table B.[18]

[17] Id. at p. 8-5, Table 8-2.

[18] Because there may be a limited number of instances where well production facilities do not have storage tanks, the proposal also provides that for tank-less facilities, the inspection schedule will be based on the facility's total VOC emissions. This provision is intended to apply to large facilities that utilize a liquids gathering system for transporting petroleum liquids to a centralized facility. These facilities are not included in the facility count used in this EIA, but because the number of these facilities in Colorado is extremely small this exclusion should have a negligible impact on the overall costs and emission reduction benefits of the proposed LDAR requirement. Additionally, because the costs and benefits from the proposed LDAR program increase at roughly the same rate, the cost effectiveness of the program for these facilities should mirror the cost effectiveness of the program as applied to facilities with tanks.

| *Table B: Proposed Leak Inspection Frequencies for Well Production Facilities* | | |
|---|---|---|
| Tank Uncontrolled Actual VOC Emissions | Current Inspection Frequency | Proposed Inspection Frequency |
| ≥ 1 tpy ≤ 6 tpy | One Time (and Monthly AVO) | Annual |
| > 6 tpy to ≤ 12 tpy | Annually | Semi-Annual |
| >12 tpy to ≤ 50 tpy | Quarterly | No Change |
| > 50 tpy | Monthly | No Change |

The Division's analysis only addresses natural gas compressor stations and well production facilities with component leak uncontrolled actual VOC emissions and tank uncontrolled actual VOC emissions, respectively, less than or equal to 12 tpy. The Division's proposed revisions to the inspection frequencies do not materially affect facilities with emissions greater than 12 tpy as these facilities are currently required to conduct more frequent inspections on a State-Only basis.

The Division utilized a multi-step process to calculate the estimated costs and benefits associated with the proposed LDAR requirements. As noted above, these costs and benefits are based on average values using the best information currently available to the Division. Costs and benefits per facility may vary. Some of the factors that could impact the costs and benefits for a particular facility include the actual number and type of components at the facility, the VOC content of the gas, whether a component is in gas or liquid service, and the travel time for the inspector to get to the facility.

First, the Division calculated an hourly inspection rate based on the total annual cost for each inspector divided by an assumed 1,880 annual work hours.[19] To calculate the total annual cost for each inspector, the Division included salary and fringe benefits for each inspector, annualized equipment and vehicle costs, and add-ons to account for supervision, overhead, travel, recordkeeping, and reporting. Based on the assumptions set forth in Table C below, the total annual cost for each inspector will be $202,536, which equates to an hourly inspection rate of $108.

| *Table C: Leak Detection and Repair (LDAR) Inspector - Annualized Cost Analysis*[20] | | | |
|---|---|---|---|
| Item | Capital Costs (one time) | Annual Costs | Annualized Total Costs |
| FLIR Camera | $127,612 | | |
| FLIR Camera Maintenance/Repair | | $7,845 | |
| Photo Ionization Detector | $5,230 | | |
| Vehicle (4x4 Truck) | $23,012 | | |
| Inspection Staff | | $78,450 | |
| Supervision (@ 20%) | | $15,690 | |
| Overhead (@10%) | | $7,845 | |
| Travel (@15%) | | $11,768 | |
| Recordkeeping (@10%) | | $7,845 | |
| Reporting (@10%) | | $7,845 | |
| Fringe (@30%) | | $23,535.0 | |
| Subtotal Costs | $155,854 | | |
| Annualized Costs* | $41,714 | $160,823 | $202,536 |
| **over 5 years at 6% ROR* | Annualized Hourly Rate | | $108 |
| | Annualized Hourly Rate + 30% Profit | | $140 |

[19] This assumes a 40 hour work week with ten holidays, two weeks of vacation, and one week of sick leave.
[20] Costs are based on the purchasing power of the US Dollar in May 2017

Because some operators will choose to utilize contractors for LDAR inspections, the Division assumed an additional 30% profit margin for all inspections to render a conservative estimate of $140 per hour for inspection costs.

Second, the Division calculated the average amount of time that it would take to conduct a Method 21 inspection at natural gas compressor stations and well production facilities based on the number of components to be inspected and assuming that a component could be inspected every 30 seconds. The Division determined the number of components based on average component counts for facility type as reflected in APENs submitted to the Division for facilities in the non-attainment area. This information provides a good average for facilities within the non-attainment area, but may not reflect facility specific component counts, and is not necessarily representative of facilities in other parts of the state.

Consistent with existing requirements under Regulation Number 7, the proposed revisions also allow owners and operators to use IR cameras either as the sole inspection tool, or as a screening tool followed by a Method 21 inspection to identify potential leaking components. An IR camera inspection or IR Camera/Method 21 hybrid inspection can be conducted more quickly than a Method 21 inspection of each component. While the Division does not currently have actual data regarding how much faster an inspection could be completed using an IR camera, for the purpose of this analysis the Division assumed that an IR camera based inspection would take 50% of the time required for a Method 21 inspection.[21]

For natural gas compressor stations, the Division used reported component counts for natural gas compressor stations within each leak rate category shown in Table A above. Based on these counts and the inspection times per component discussed above, the Division calculated that the total time to conduct an IR camera inspection of a natural gas compressor station with component leak uncontrolled actual VOC emissions less than or equal to 12 tpy would be 10.6 hours.

| *Table D: Calculated Inspection Time Compressor Station Leak Inspections* | | |
|---|---|---|
| Component Leak Uncontrolled Actual VOC Emissions in NAA | Method 21 Inspection | IR Camera/ Hybrid Inspection |
| ≤ 12 tpy | 21.2 hours | 10.6 hours |

The Division has limited data on the number of components per well production facility. Based on the limited available data, there appears to be a distinction between component numbers at well production facilities in the DMNFR and well production facilities outside the DMNFR. Accordingly, the Division calculated inspection times based on the data available for well production facilities in the DMNFR, as shown in Table E below, because the Division's proposed revisions do not affect well production facilities outside of the DMNFR. The Division calculated that the time to conduct an IR camera inspection of a well production facility in the DMNFR with tank uncontrolled actual VOC emissions between 1 and 12 tpy would be 6.1 hours.

| *Table E: Calculated Inspection Times for Well Production Facility Leak Inspections* | | |
|---|---|---|
| Area | Method 21 Inspection | IR Camera/ Hybrid Inspection |
| DMNFR | 12.2 hours | 6.1 hours |

Next, the Division calculated the projected inspection costs for both natural gas compressor stations and well production facilities. The Division used industry reported emission data to determine the number of facilities that will be subject to the proposed quarterly (for natural

[21] Based on the Division's own IR camera inspections, and reports from various parties during the stakeholder and prehearing process it appears that the Division's assumption may significantly overstate the actual time needed to conduct an IR camera inspection.

gas compressor stations) or annual or semi-annual (for well production facilities) inspection frequencies, and multiplied those inspections by the calculated inspection time and projected hourly inspection rate. For natural gas compressor stations and well production facilities, the Division assumed that all inspections would be conducted by third-party contractors in an effort to make a conservative cost estimate.

The Division has included both repair costs and estimated product savings from conducting leak detection activities. To calculate repair costs, the Division used EPA information regarding leaking component rates, component repair times, and hourly repair rates. Specifically, the Division assumed a $76.78 hourly rate to repair components, and an average repair time of between 0.17 hours and 16 hours, depending on the type of component and the complexity of the repair.[22] To calculate the number of leaking components the Division used industry reported component counts and assumed a 1.18% leaking component rate for facilities subject to annual inspections, 1.48% leaking component rate for facilities subject to semi-annual inspections and a 1.77% leaking component rate for facilities subject to quarterly inspections.[23] To calculate the value of the additional product captured, the Division converted the amount of VOC and methane/ethane reduced to one thousand cubic feet (MCF) of natural gas, assuming a price of $3.13/MCF. With respect to re-monitoring, the Division determined that additional costs associated with re-monitoring are negligible because re-monitoring can be undertaken at the same time as repair.

For natural gas compressor stations ≤ 12 tpy, the existing Regulation Number 7 requires an annual inspection. The proposed revisions increase the inspection frequency to quarterly. Thus, to properly account for the increased inspection frequency and associated costs, the Division analyzed the incremental change related to the revised inspection frequency. Based on the above methodology, the annual inspection cost for natural gas compressor stations is set forth in Table F below.

***Table F: Compressor Stations With fugitive VOC Emissions ≤ 12 tpy Leak Inspection Costs (@ $140/hr) Using IR Camera/Method 21 Hybrid***

| Regulatory Scenario | Number of Compressor Stations in DMNFR | Annual Inspection Frequency | Time per IR Camera Inspection [hours] | Total Annual Inspection Time [hours] | Total Annual Inspection Cost |
|---|---|---|---|---|---|
| Existing Reg. | 53 | 1 | 10.6 | 561.8 | $78,652 |
| Proposed Reg. | 53 | 4 | 10.6 | 2,247.2 | $314,608 |
| Incremental Change | | 3 | | 1,685.4 | $235,956 |

Repair costs associated with these inspections are shown in Table G and fuel savings associated with these repairs are shown in Table H.

***Table G: Compressor Stations With fugitive VOC Emissions ≤ 12 tpy Leak Repair Costs***

[22] See "Equipment Leak Emission Reduction and Cost Analysis for Well Pads, Gathering and Boosting Stations, and Transmission and Storage Facilities Using Emission and Cost Data From the Uniform Standards," Bradley Nelson and Heather Brown, April 17, 2012; "Analysis of Emissions Reduction Techniques for Equipment Leaks," Cindy Hancy, December 21, 2011. Hourly repair cost is adjusted for inflation to May 2017.
[23] This leaking component rate is consistent with the rate that the Louis Berger Group used in their Initial Economic Impact Analysis for Industry's Proposed Revisions to Colorado's Air Quality Control Commission Regulation No. 7 (DGS-PHS Ex. C), and is based on the leak rate utilized by Nelson and Brown in their analysis of leak reduction costs and benefits.

| Regulatory Scenario | Number of Compressor Stations in DMNFR | Leak Repair Rate [$/hr] | Number of Leaks per Compressor Station | Total Leak Repair Time per CS [hours] | Total Annual Repair Cost |
|---|---|---|---|---|---|
| Existing Reg. | 53 | $76.78 | 30.1 | 23.0 | $93,595 |
| Proposed Reg. | 53 | $76.78 | 45.1 | 34.6 | $140,799 |
| Incremental Change | | | 15.0 | 11.6 | $47,204 |

| *Table H: Compressor Stations With fugitive VOC Emissions ≤ 12 tpy Recovered Natural Gas Value from Leak Repairs* | | | | | |
|---|---|---|---|---|---|
| Regulatory Scenario | Number of Compressor Stations in DMNFR | Total Recovered Natural Gas per CS [tons/year] | Value of Natural Gas [$/MCF] | Conversion Factor [MCF/ton] | Total Annual Value of Recovered Natural Gas |
| Existing Reg. | 53 | 10.2 | $3.59 | 35.8 | $60.624 |
| Proposed Reg. | 53 | 15.4 | $3.59 | 35.8 | $91,530 |
| Incremental Change | | 5.2 | | | $30,906 |

The total net costs for natural gas compressor station LDAR are set forth in Table I. The incremental increase is the estimated cost associated with revising the inspection frequency from annual to quarterly.

| *Table I: Compressor Stations With fugitive VOC Emissions ≤ 12 tpy Net Leak Inspection and Repair Costs* | | | | | |
|---|---|---|---|---|---|
| Regulatory Scenario | Number of Compressor Stations in DMNFR | Total Annual Inspection Cost | Total Annual Repair Cost | Total Annual Value of Recovered Natural Gas | Net Annual Leak Inspection and Repair Costs |
| Existing Reg. | 53 | $78,652 | $93,595 | -$60,624 | $111,623 |
| Proposed Reg. | 53 | $314,608 | $140,799 | -$91,530 | $363,877 |
| Incremental Increase | | $235,956 | $47,204 | -$30,906 | $252,254 |

Finally, the Division calculated the cost effectiveness of the proposed LDAR requirements based on the costs identified above and the projected emission reductions. To determine emission reductions, the Division first calculated VOC and methane emissions, assuming no inspections and based on the reported component counts, standard emission factors for these components, and the average fraction of VOC and non-VOC emissions (methane/ethane). Based on EPA reported information, the Division calculated a 40% emissions reduction for annual inspections, a 50% reduction for semi-annual inspections, and a 60% reduction for quarterly inspections. Some operators have raised questions about the accuracy of these percentage reductions, and in particular whether the semi-annual and quarterly inspections provide the projected incremental benefits relative to annual inspections. To date, however, the Division has not been provided or identified data supporting different incremental benefits for semi-annual and quarterly inspections. To the extent that such data is developed moving forward, it could justify the reconsideration of the benefits of moving to semi-annual or quarterly inspections.

Using this information, the Division calculated the total emission reductions and the incremental emissions reductions from leaks at natural gas compressor stations in the non-attainment area as shown below in Table J.

| *Table J: Compressor Stations With fugitive VOC Emissions ≤ 12 tpy Leak Inspection* |
|---|

| *Emission Reductions* | | | | | | |
|---|---|---|---|---|---|---|
| Regulatory Scenario | Number of Comp Stations in DMNFR | LDAR Program Reduction % | VOC Emissions Reduction for each CS tier [tpy] | Total VOC Reduction [tpy] | Methane-Ethane Emissions Reduction for each CS [tpy] | Total Methane-Ethane Reduction [tpy] |
| Existing Reg. | 53 | 40% | 4.0 | 212 | 6.2 | 329 |
| Proposed Reg. | 53 | 60% | 6.1 | 323 | 9.3 | 493 |
| Incremental Emissions Reduction | | | | 111 | | 164 |

Based on the proposed increase in the inspection frequency at natural gas compressor stations, there are additional or "incremental" emission reductions shown in Table J above. By increasing the frequency of leak inspections at natural gas compressor stations with emissions less than or equal to 12 tpy to quarterly, the estimated incremental cost effectiveness is $2,284/ton of VOC reduced, as shown in Table K.

| *Table K: Compressor Stations With fugitive VOC Emissions ≤ 12 tpy Leak Inspection Cost Effectiveness using IR Camera/Method 21* | | | | | | |
|---|---|---|---|---|---|---|
| Regulatory Scenario | LDAR Program Reduction % | Total Net Annual Inspection & Repair Cost | Total VOC Reduction [tpy] | VOC Control Cost [$/ton] | Total Methane-Ethane Reduction [tpy] | Methane-Ethane Control Cost [$/ton] |
| Existing Reg. | 40% | $111,623 | 212 | $527 | 329 | $339 |
| Proposed Reg. | 60% | $363,877 | 323 | $1,127 | 493 | $738 |
| Incremental cost effectiveness of additional emission reductions | | $252,254 | 111 | $2,273 | 164 | $1,538 |

Using the same multi-step process for well production facilities with storage tank uncontrolled actual VOC emissions between 1 and 12 tpy, the estimated annual inspection costs are set forth in Tables L -Q below. The incremental change is the estimated cost associated with revising the inspection frequency from one-time to annual (for ≥ 1 tpy ≤ 6 tpy tanks) and annual to semi-annual (for > 6 tpy < 12 tpy tanks).

| *Table L: Well Production Facility Leak Inspection Costs (@ $140/hr) Using IR Camera/Method 21 Hybrid* | | | | | |
|---|---|---|---|---|---|
| Regulatory Scenario | Number of Facilities in DMNFR | Annual Inspection Frequency | Total Number of Inspections | Inspection Time Per Inspection [hours] | Total Annual Inspection Cost |
| Uncontrolled VOC at Tank Battery: ≥ 1 tpy ≤ 6 tpy | | | | | |
| Existing Reg. | 2,958 | one-time inspection satisfied in 2015 | | | |
| Proposed Reg. | 2,958 | 1 | 2,958 | 6.1 | $2,526,132 |
| Incremental Change | | 1 | 2,958 | | $2,526,132 |
| Uncontrolled VOC at Tank Battery: > 6 tpy ≤ 12 tpy | | | | | |
| Existing Reg. | 1,370 | 1 | 1,370 | 8,857 | $1,169,980 |
| Proposed Reg. | 1,370 | 2 | 2,740 | 16,714 | $2,339,960 |

| | | | | |
|---|---|---|---|---|
| Incremental Change | 1 | 1,370 | 8,857 | $1,169,980 |

***Table M: Well Production Facility Leak Repair Costs***

| Regulatory Scenario | Number of Facilities in DMNFR | Leak Repair Rate [$/hr] | Number of Leaks per Tank | Total Leak Repair Time per Tank [hours] | Total Annual Repair Cost |
|---|---|---|---|---|---|
| Uncontrolled VOC at Tank Battery: ≥ 1 tpy ≤ 6 tpy | | | | | |
| Existing Reg. | 2,958 | one-time inspection satisfied in 2015 | | | |
| Proposed Reg. | 2,958 | $76.78 | 17 | 11.8 | $2,679,960 |
| Incremental Change | | | 17 | 11.8 | $2,679,960 |
| Uncontrolled VOC at Tank Battery: > 6 tpy ≤ 12 tpy | | | | | |
| Existing Reg. | 1,370 | $76.78 | 17.0 | 11.8 | $1,241,225 |
| Proposed Reg. | 1,370 | $76.78 | 21.3 | 14.8 | $1,556,791 |
| Incremental Change | | | 4.3 | 3.0 | $315,566 |

***Table N: Well Production Facility Recovered Natural Gas Value from Leak Repairs***

| Regulatory Scenario | Number of Facilities in DMNFR | Total Recovered Natural Gas per tank [tons/year] | Value of Natural Gas [$/MCF] | Conversion Factor [MCF/ton] | Total Annual Value of Recovered Natural Gas |
|---|---|---|---|---|---|
| Uncontrolled VOC at Tank Battery: ≥ 1 tpy ≤ 6 tpy | | | | | |
| Existing Reg. | 2,958 | one-time inspection satisfied in 2015 | | | |
| Proposed Reg. | 2,958 | 4.6 | $3.13 | 35.8 | $1,524,696 |
| Incremental Change | | 4.6 | | | $1,524,696 |
| Uncontrolled VOC at Tank Battery: > 6 tpy ≤ 12 tpy | | | | | |
| Existing Reg. | 1,370 | 4.6 | $3.13 | 35.8 | $706,164 |
| Proposed Reg. | 1,370 | 5.8 | $3.13 | 35.8 | $890,381 |
| Incremental Change | | 1.2 | | | $184,217 |

***Table O: Well Production Facility -Net Leak Inspection and Repair Costs***

| Regulatory Scenario | Number of Well Production Facilities in DMNFR | Total Annual Inspection Cost | Total Annual Repair Cost | Total Annual Value of Recovered Natural Gas | Net Annual Leak Inspection and Repair Costs |
|---|---|---|---|---|---|
| Uncontrolled VOC at Tank Battery: ≥ 1 tpy ≤ 6 tpy | | | | | |
| Existing Reg. | 2,958 | one-time inspection satisfied in 2015 | | | |
| Proposed Reg. | 2,958 | $2,526,132 | $2,679,960 | -$1,524,696 | $3,681,396 |
| Incremental Increase | | $2,526,132 | $2,679,960 | -$1,524,696 | $3,681,396 |
| Uncontrolled VOC at Tank Battery: > 6 tpy ≤ 12 tpy | | | | | |
| Existing Reg. | 1,370 | $1,169,980 | $1,241,225 | -$706,164 | $1,705,041 |
| Proposed Reg. | 1,370 | $2,339,960 | $1,556,791 | -$890,381 | $3,006,370 |
| Incremental Increase | | $1,169,980 | $315,566 | -$184,217 | $1,301,329 |

The incremental increase provides the estimated costs associated with changing the inspection frequency from one-time to annual (for ≥ 1 tpy ≤ 6 tpy tanks) and annual to semi-annual (for > 6 tpy < 12 tpy tanks).

| *Table P: Well Production Facility Leak Inspection Emission Reductions* | | | | | | |
|---|---|---|---|---|---|---|
| Regulatory Scenario | Number of Facilities in DMNFR | LDAR Program Reduction % | VOC Emissions Reduction for each Tank Battery [tpy] | Total VOC Reduction [tpy] | Methane-Ethane Emissions Reduction for each Tank Battery [tpy] | Total Methane-Ethane Reduction [tpy] |
| Uncontrolled VOC at Tank Battery: ≥ 1 tpy ≤ 6 tpy | | | | | | |
| Existing Reg. | 2,958 | one-time inspection satisfied in 2015 | | | | |
| Proposed Reg. | 2,958 | 40% | 1.8 | 5,324 | 2.8 | 8,282 |
| Incremental Emissions Reduction | | | 1.8 | 5,324 | 2.8 | 8,282 |
| Uncontrolled VOC at Tank Battery: > 6 tpy ≤ 12 tpy | | | | | | |
| Existing Reg. | 1,370 | 40% | 1.8 | 2,466 | 2.8 | 3,836 |
| Proposed Reg. | 1,370 | 50% | 2.3 | 3,151 | 3.5 | 4,795 |
| Incremental Emissions Reduction | | | 0.5 | 685 | 0.7 | 959 |

Based on the emission reductions in Table P, the estimated cost effectiveness of annual (for ≥ 1 tpy ≤ 6 tpy tanks) and semi-annual (for ≥ 6 tpy < 12 tpy tanks) leak inspections at well production facilities with storage tank uncontrolled actual VOC emissions between 1 and 12 tpy is shown in Table Q.

| *Table Q: Well Production Facility Leak Cost-Effectiveness Using IR Camera/Method 21* | | | | | | |
|---|---|---|---|---|---|---|
| Regulatory Scenario | Number of Facilities in NAA | Total Net Annual Leak Inspection & Repair Cost | Total VOC Red. [tpy] | VOC Control Cost [$/ton] | Total Methane-Ethane Red. [tpy] | Methane-Ethane Control Cost [$/ton] |
| Uncontrolled VOC at Tank Battery: ≥ 1 tpy ≤ 6 tpy | | | | | | |
| Existing Reg. | 2,958 | one-time inspection satisfied in 2015 | | | | |
| Proposed Reg. | 2,958 | $3,681,396 | 5,324 | $691 | 8,282 | $445 |
| Incremental cost effectiveness of additional emission reductions | | $3,681,396 | 5,324 | $691 | 8,282 | $445 |
| Uncontrolled VOC at Tank Battery: > 6 tpy ≤ 12 tpy | | | | | | |
| Existing Reg. | 1,370 | $1,705,041 | 2,466 | $691 | 3,836 | $445 |
| Proposed Reg. | 1,370 | $3,006,370 | 3,151 | $954 | 4,795 | $627 |
| Incremental cost effectiveness of additional emission reductions | | $1,301,329 | 685 | $1,900 | 959 | $1,357 |
| Uncontrolled VOC at Tank Battery: ≥ 1 tpy ≤ 12 tpy | | | | | | |
| Overall incremental cost effectiveness of additional emission reductions | 4,328 | $4,982,725 | 6,009 | $829 | 9,241 | $539 |

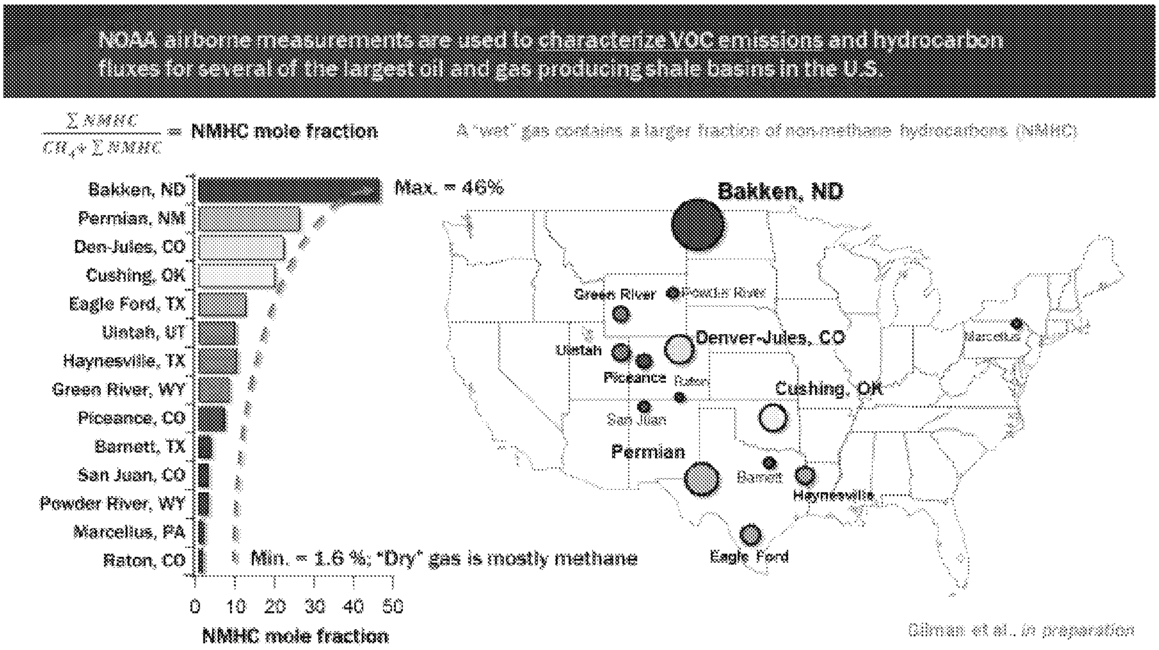
The Division calculated the incremental cost effectiveness by subtracting the costs and effectiveness of the existing regulation from the proposed regulation. For well production facilities with uncontrolled actual VOC ≥ 1 tpy ≤ 6 tpy, the average cost effectiveness of the proposed revisions is estimated to be $691/ton of VOC reduced. For well production facilities with uncontrolled actual VOC > 6 tpy ≤ 12 tpy, the average incremental cost effectiveness of increasing the inspection frequency to semi-annual is estimated to be $1,900/ton of VOC reduced. The overall average incremental cost effectiveness of the proposed revisions for well production facilities with VOC emissions between 1 and 12 tpy is $829/ton of VOC reduced.

Over the past decade, technical innovations in the oil and gas sector has resulted in a transition from drilling only vertical wells with single-stage separation to exclusively drilling horizontal wells with multi-stage separation. The above LDAR analysis uses the best available data for well production facilities and relies on APEN reported tank battery data reflecting a mix of both vertical and horizontal wells along with a variety of separator stages. Information reported to the Division does not draw a distinction between horizontal and vertical well facilities. Accordingly, while there may be distinctions between the cost effectiveness of these two different types of facilities, that information is not currently available to the Division.

One important distinction between vertical and horizontal well facilities is not based on the cost effectiveness of the program on a dollar per ton basis, but rather impacts whether the revenue from the facility can support the costs of the LDAR program. In the DMNFR, vertical wells with a single stage of separation are typically reported using a default uncontrolled VOC emission factor of 13.7 pounds per barrel (lbs/bbl) as specified in Regulation Number 7, Section XII.C.2.a.(i). In the situation of marginal vertical well production facilities near the lower LDAR threshold (1.0 tpy actual uncontrolled VOC), the estimated crude oil production is about 146 bbl/yr along with an unknown quantity of natural gas. Considering the uncertainties in the future prices of crude oil and natural gas along with the lack of industry specific data on the actual costs of leak detection and repair, the Division acknowledges that the actual LDAR costs may affect the profitability of marginally producing wells, notwithstanding the fact that LDAR may be cost effective based solely on a cost per ton analysis.

As reflected above, the Division's cost assessments are limited to facilities within the DMNFR. Certain parties have indicated that the proposed revisions should also apply in other parts of the state. Because of differences in the types of facilities, component counts, and travel times, merely applying the above cost analysis without adjustments to facilities outside the non-attainment area may not be fully representative. Additionally, differences in VOC content of the gas may have impacts on the cost effectiveness of conducting LDAR inspections. The below Figure 1, from NOAA, shows the non-methane hydrocarbon mole fraction associated with a number of oil and gas basins nationwide. Unlike the "wet gas" of the DJ Basin where high concentrations of VOCs are flashed from the crude oil in the storage tank, other oil and gas production areas of the state, such as the Piceance Basin, have much lower hydrocarbon liquids and generally produce "dry gas" with much lower VOC levels at the well production facility. Accordingly, the VOC reduction benefit from potential LDAR at well production facilities outside the DMNFR may be more limited.

Figure 1:




Similar to the analysis above, the Oil and Gas CTG estimated costs for preparing an OGI emission monitoring and repair plan for a company-defined area that included labor, reading of the rule, development of a fugitive emission monitoring plan, initial activities planning, semi-annual or quarterly monitoring, notifications, a Method 21 device, subsequent activities, OGI monitoring, repair, resurvey, and annual reports.[24] The Oil and Gas CTG estimated the total capital cost at $17,620 per company defined area for semi-annual monitoring and $801 per well assuming 22 well sites within a company defined area, with a cost per ton VOC reduced ranging $2,494 to $11,503 without natural gas savings and depending on the type of well site.[25] The Oil and Gas CTG estimated the total capital cost of $16,753 per facility and $2,393 per gathering and boosting station assuming 7 stations within a 210 mile radius, with a cost per ton VOC reduced at $3,205 without natural gas savings.[26]

The Oil and Gas CTG also estimated annual repair costs at $299 for well sites and $3,436 for gathering and boosting stations per survey, assuming that 1.18% of components leak and 75% are repaired online and 25% are repaired offline.[27] The Oil and Gas CTG estimated average fugitive emission component counts for a natural gas well site model plant at 139 valves, 510 connectors, 15 open-ended lines, and 7 pressure relief valves.[28] The Oil and Gas CTG estimates average fugitive emission component counts for an oil well site model plant $\geq$ 300 GOR at 68 valves, 54 flanges, 186 connectors, 2 open-ended lines, and 4 pressure relief valves.[29] The Oil and Gas CTG estimates average fugitive emission component counts for a production gathering and boosting station model plant at 906 valves, 2,864 connectors, 83 open-ended lines, and 48 pressure relief valves.[30]

Lastly, the Oil and Gas CTG estimated the capital cost of a semi-annual EPA Method 21 emission monitoring repair plan at a 500 ppm repair threshold at $1,460 per well, with a cost per ton VOC reduced ranging $3,392 to $15,648 without natural gas savings depending on the

[24] Oil and Gas CTG at p. 9-22 - 9-22.
[25] Id. at p. 9-24.
[26] Id.
[27] Id. at p. 9-23.
[28] Id. at p. 9-15, Table 9-7.
[29] Id. at p. 9-16, Table 9-8.
[30] Id. at p. 9-18, Table 9-9.

type of well site.[31] The Oil and Gas CTG estimated the capital cost of a quarterly monitoring program at $4,679 per gathering and boosting station, with a cost per ton VOC reduced at $4,004 without natural gas savings.[32]

Pneumatic controllers (Section XVIII.F.)

The proposed revisions require owners or operators of existing and new natural gas-driven pneumatic controllers located at or upstream of a natural gas processing plant to operate and maintain pneumatic controllers consistent with good engineering practices. The proposed revisions also require owners or operators of existing and new natural gas-driven pneumatic controllers at well production facilities and natural gas compressor stations to inspect and determine whether the pneumatic controller is operating properly. The owner or operator would screen the pneumatic controllers with an infra-red camera or EPA's Method 21, and further inspect pneumatic controllers where emissions were observed to determine whether the pneumatic controller is operating properly. If the pneumatic controller is operating properly, no further action is required of the owner or operator. However, if an owner or operator found that a pneumatic controller was not operating properly, the proposed revisions require the owner or operator to take actions to return the device to proper operation. The proposed revisions also require the owner or operator to document and report pneumatic controller inspection and enhanced response activities. While the Oil and Gas CTG notes the value of pneumatic controller inspection and maintenance, the Oil and Gas CTG does not specify a pneumatic controller inspection and maintenance as presumptive RACT. Therefore the revisions are proposed as State-Only. The Division notes that the pneumatic controller inspection and enhanced response proposal for well production facilities and natural gas compressor stations represents a pioneering approach to finding and fixing malfunctioning pneumatic controllers that could result in further reductions in VOC emissions in the DMNFR. However, the Division's proposal minimizes costs by requiring pneumatic controllers to be inspected on the same schedule as well production facilities and natural gas compressor stations. A "pneumatics" task force will track the implementation of the program and assess the costs and benefits.

The Division estimates that there are 7,264 well production facilities and 73 natural gas compressor stations in the DMNFR. The Division also estimates that there are approximately 53,000 natural gas-driven pneumatic controllers at well production facilities in the DMNFR. Under the proposed revisions, owners or operators of the well production facilities would inspect pneumatic controllers annually or semi-annually for proper operation, depending on the VOC emissions of the well production facility. Similarly, owners or operators of natural gas compressor stations would inspect pneumatic controllers quarterly for proper operation. The proposed revisions build upon the LDAR program in Regulation Number 7 and the Division assumes that owners or operators would incorporate the pneumatic controller inspections into their well production facility and natural gas compressor station LDAR programs. Therefore, the Division believes that the inspection and recordkeeping costs are likely minimal. The Oil and Gas CTG estimates for the well site and gathering and boosting station LDAR program a resurvey cost assuming five minutes per leak at $57.80 per hour at well sites and the preparation of an annual report to take one person 4 hours at a cost of $231.[33]

There may also be costs related to activities necessary to return a pneumatic controller to proper operation. Because methods to maintain a pneumatic controller are highly variable, costs are also variable based on labor, time, and repair or replacement parts. The mean time between first and subsequent device failures depends on the quality and composition of the gas stream, temperature variation, and rate of actuation. According to manufacturers, pneumatic

[31] Id. at p. 9-30, Table 9-15.
[32] Id. at p. 9-31, Table 9-16.
[33] Id. at p. 9-32.

controller repair kits can range from $10 to $125, and repair time from 15 minutes to 1 hour per pneumatic controller. Some repairs may require well shut-in and incur additional costs.

However, there are likely cost savings related to maintaining and returning pneumatic controllers to proper operation due to product savings. Tuning pneumatic controllers and using the proper process settings will help maintain optimal conditions and reduce emissions. The Oil and Gas CTG notes that emissions from natural gas-driven pneumatic controllers in the field can be higher than the reported gas consumption due to operating conditions, age, and wear of the device.[34] The Oil and Gas CTG provides examples of factors increasing emissions such as nozzle corrosion, broken or worn diaphragms and fittings, improper installation, lack of maintenance, lack of calibration, debris on the vent or supply pilot, and wear in the seal seat.[35] The Oil and Gas CTG concluded that maintenance of pneumatic controllers, such as cleaning and tuning, repairing leaking gaskets and seals, and eliminating unnecessary valve positions can save 5 to 18 scfh per device.[36] Similarly, the 2016 NSPS OOOOa TSD notes that pneumatic controllers in poor condition typically bleed 5 to 10 scfh more than representative conditions due to work seals or gaskets, nozzle corrosion or wear, or lose control tube fittings.[37] The 2016 NSPS OOOOa TSD also notes that enhanced maintenance to repair and maintain pneumatic devices can reduce emissions but that methods and costs are variable.[38] EPA's Natural Gas Star Options For Reducing Methane Emissions From Pneumatic Devices In The Natural Gas Industry (2006) also estimates that the maintenance of natural gas-driven pneumatic controllers can save 45 to 260 mcf/year of natural gas, with implementation costs described as negligible to $500.[39] Specifically, costs to reduce gas bleed are estimated for reducing supply pressure at $207, repairing leaks and retuning at $31, changing level controller gain settings at $0, and removing unnecessary positioners as $0.[40] EPA estimates the payback period for cost associated with these activities ranges from immediate to three months.[41]

The Division requested that owners or operators of natural gas-driven pneumatic controllers in the DMNFR provide Colorado specific cost information concerning the proposed revisions; however, the Division recognizes that this information may not exist, but expects the pneumatics task force to develop this information through their process.

### (C) Incorporation of an estimate of the economic impact of the proposal on the supporting business and industrial sectors associated with the primary affected business or industry sectors

The proposed revisions may result in positive economic impacts to supporting business that contractually conduct leak inspections, repair activities, and reporting services as some owners and operators may choose to contract a company to conduct the proposed inspection and reporting requirements. The proposed revisions may also result in positive economic impacts to equipment suppliers as some owners and operators may have to replace equipment in order to comply with the proposed revisions. It is difficult to quantify these economic impacts because the extent to which consultants assist with inspections, reporting, and analyses is unknown.

The Division requested that supporting business and industry provide Colorado specific cost information concerning the proposed revisions.

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[34] Id. at p. 6-19.
[35] Id.
[36] Id. at p. 6-20.
[37] NSPS OOOOa TSD at p. 64, Table 5-3.
[38] Id.
[39] EPA Options For Reducing Methane Emissions From Pneumatic Devices In The Natural Gas Industry at p. 1 (October 2006).
[40] Id. at p. 5.
[41] Id.

## SUMMARY AND CONCLUSION

The Division prepared this Final Economic Impact Analysis in accordance with the requirements of Section 25-7-110.594), C.R.S. Specifically, the Division utilized the methodology identified in Section 25-7-110.5(4)(c)(III), C.R.S.

The Division has determined that there may be costs related to the proposed monitoring and recordkeeping requirements for centrifugal compressors, reciprocating compressors, and continuous bleed pneumatic controllers. Because the proposed revisions build upon existing requirements, the Division believes these costs are likely minimal.

There may be economic impacts of the proposed inspection frequency or leak threshold increases for the LDAR programs at well production facilities, natural gas compressor stations, and natural gas processing plants. The proposed requirements building upon existing requirements, and the Division requested owners or operators of these facilities provide Colorado specific cost information concerning the impacts of the proposed revisions.

Lastly, there may be economic impacts of the proposed pneumatic pump, natural gas processing plant reciprocating compressor, natural gas processing plant pneumatic controller, and pneumatic controller inspection and enhanced response requirements as these would be new requirements for this equipment.

Based on the above analyses, the Division believes the proposed revisions are cost-effective. The Division has provided an estimate of costs based on reasonably available information and will consider any additional information provided by stakeholders. The Division requests that affected industry or any interested party submit information with regard to the cost of compliance with these proposed rule revisions.